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SHININGBANK ENERGY INCOME FUND

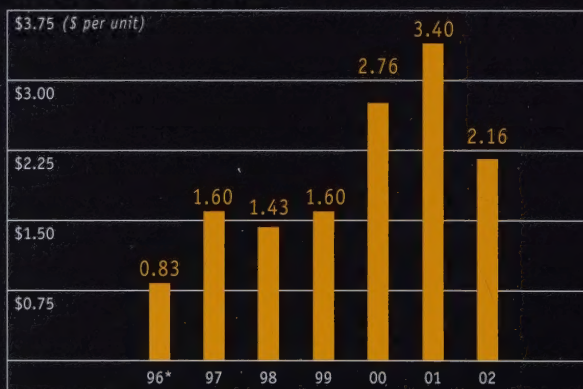
2002 ANNUAL REPORT

28% compound rate of return since inception in 1996

Shiningbank Energy Income Fund

	2002	2001	% change
FINANCIAL (000s, except Trust Unit amounts)			
Oil and natural gas sales	\$ 142,661	\$ 170,714	(16)%
Distributable income	69,607	81,979	(15)%
Distributions per Trust Unit	\$ 2.16	\$ 3.40	(36)%
Acquisition and development costs	63,144	323,204	(80)%
Long term debt	115,283	122,459	(6)%
OPERATIONS			
Average daily production			
Oil (bbl/d)	2,054	2,013	2%
Natural gas (mmcf/d)	64.2	61.6	4%
NGL (bbl/d)	1,454	1,288	13%
Oil equivalent (boe/d @ 6:1)	14,214	13,564	5%

TOTAL CASH DISTRIBUTIONS



* 6 months only

- ▲ Cash distributions alone provided a 15.5% return in 2002.

COVER The Fund is named after Shiningbank Lake, located west of Edmonton, Alberta, which is close to one of the first properties acquired by the Fund. The name Shiningbank comes from the Aboriginal word for the lake describing its clay banks that shine like gold in the sun.

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Unitholders receive strong cash distributions

Since Shiningbank was formed in mid-1996, our investors have received cash distributions and rates of return that have often been the highest in the sector. We acquire quality producing assets, primarily natural gas, and manage the production and marketing to capture commodity price highs and bridge pricing lows. Shiningbank's units trade on the TSX under

SHN.UN





We consistently deliver superior returns . . .

▲ INDUSTRY TOP PERFORMER

The Fund's 28% total return since inception is the highest among our peer group – those funds that have been operating for the same amount of time or longer.

▲ 24% RETURN IN 2002

Our investors received a 24% return in 2002 based on \$2.16 paid in cash distributions and \$1.18 growth in the price of our units at year end.

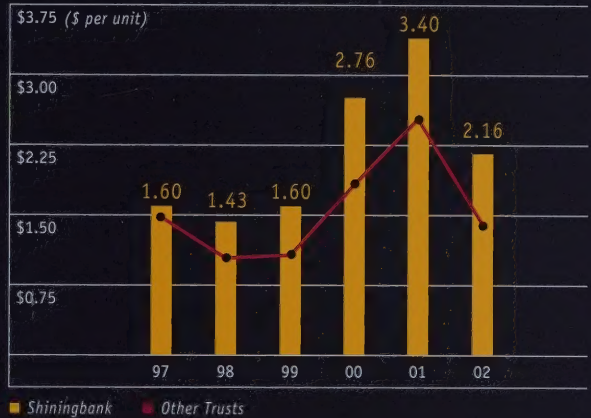
*Unitholders now receive
their cash distribution every month.*



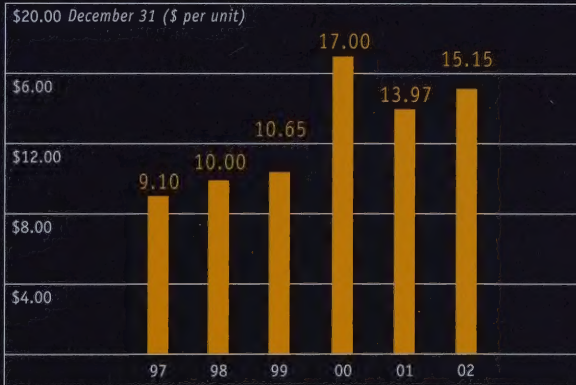
Our investment performance . . .

- △ Cash distributions have consistently been higher than the average of other oil and gas trusts.

SHININGBANK ANNUAL CASH DISTRIBUTIONS
VERSUS AVERAGE OF OTHER TRUSTS



PRICE PER TRUST UNIT



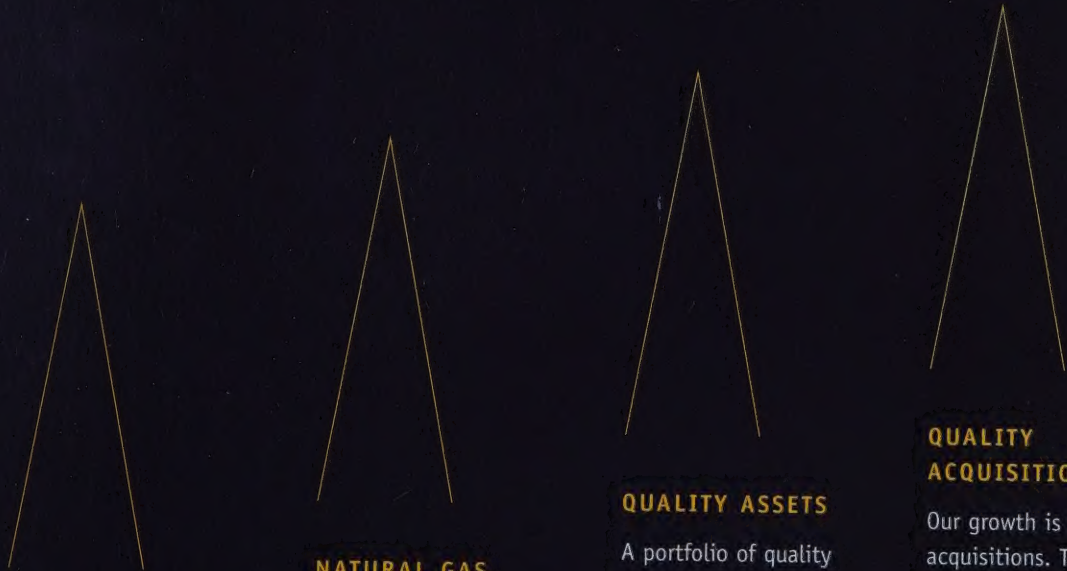
- △ The strength in our unit price indicates market support for our natural gas focus and track record.

TOTAL RETURN BREAKDOWN



- △ Total return consists of cash distributions plus the change in the unit price.

We keep our skills sharpened . . .



CAPTURING PRICING HIGHS; BRIDGING THE LOWS

We concentrate on capturing pricing highs for natural gas and managing risk to bridge pricing lows.

NATURAL GAS

Shiningbank is primarily a natural gas producer – 75% of production. We believe that natural gas is the fossil fuel that will generate the highest returns over time.

QUALITY ASSETS

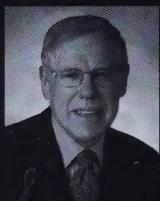
A portfolio of quality assets helps reduce production risk and stabilizes cash flow. Our properties are primarily natural gas with long-life reserves, relatively stable production and low decline rates.

QUALITY ACQUISITIONS

Our growth is driven by acquisitions. To ensure acquisitions are immediately accretive to unitholders, and to ensure the long-term viability of the Fund, all acquisitions are carefully evaluated for quality, timing, price and operational fit. We only purchase properties when the price and timing are right; we do not buy just for the sake of growth.

How we deliver superior returns . . .

Directors and Management



EDWARD W. BEST

Director

Ted has 50 years experience in the industry including being President of the Oil and Gas Division and a director of BP Canada. He has been a consultant in the domestic and international petroleum industry, and a director of a number of senior and junior oil and gas companies. Ted is an inductee into the Canadian Petroleum Hall of Fame and is an Honourary Member of the Canadian Society of Petroleum Geologists.



WARREN D. STECKLEY

Director

Warren combines extensive oil and gas experience with financial and investment expertise. He is currently President and Chief Operating Officer for Barnwell of Canada, Limited, an oil and gas company and wholly-owned subsidiary of Barnwell Industries Inc., a public company that trades on the American Stock Exchange. He is also a director of several private and public oil and gas companies.



D. GRANT GUNDERSON

Director

Grant's extensive industry experience ranges from Vice-President, Economics and Planning for Canadian Superior Oil Ltd. to Manager of the heavy oil division for Mobil Oil Canada; and working with Mobil in a planning capacity in New York and Fairfax, Virginia. He is currently an associate with the investment firm of Sayer Securities Limited.



ARNE R. NIELSEN

Executive Chairman

Arne is one of the pioneers of the Canadian oil and gas industry. He has over 50 years experience in the industry including 10 years as President of Mobil Oil Canada Ltd. His contributions have been honoured in many ways including: inductee into the Petroleum Hall of Fame, an Honourary Doctorate from the University of Alberta, and he was named to the list of Albertans who had an impact on the 20th century.



DAVID M. FITZPATRICK

President and Chief Executive Officer

Dave is a geological engineer who brings considerable technical expertise to the role of President and Chief Executive Officer. This skill is combined with over 20 years industry experience, much of it in senior management with some of the industry's largest public companies. Dave is on the Board of Governors of the Canadian Association of Petroleum Producers.



GREGORY D. MOORE

Vice President, Operations

As a petroleum engineer, Greg has over 30 years experience working with senior and junior companies in both Canada and Australia. With responsibility for all field operations – from drilling to reservoir management – he has a broad base of technical expertise encompassing production optimization and reservoir performance.



BRUCE K. GIBSON

Vice President, Finance & Chief Financial Officer

With over 25 years industry experience, Bruce has been the senior financial executive in several gas-weighted public companies. His extensive expertise includes hands-on oil and gas financial management, commodity marketing and public equity market issues.



TERRY P. PROKOPY

Vice President, Land

Terry has 30 years of top-level land experience working for both major and junior companies in Western Canada. Terry plays a key role in identifying and evaluating acquisition targets for the Fund.



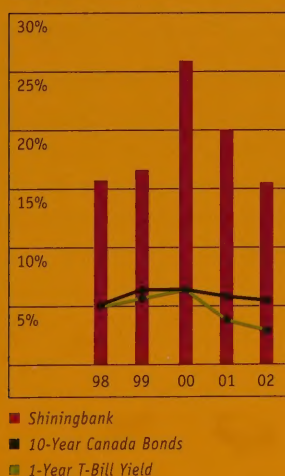
Fellow Unitholders

2002 was a year of turmoil for investors and stock markets. Yet at Shiningbank, we were able to meet our prime objective: providing superior returns compared to traditional investment vehicles. For 2002, our rate of return was 24%, a calculation that includes distributions paid to our unitholders and the strength of our unit price.

We also lay claim to a milestone within our trust sector. Since our inception in mid-1996, our investors have received a 28% compound annual rate of return, the highest among our peers – those funds that have been operating for the same amount of time or longer. We see this as an important measure because hitting one home run can be easy, or maybe lucky. To consistently out-perform traditional investments – and to be a top performer among our peers – takes the right combination of strategy and experience.

As we enter 2003, stock markets are still in the doldrums and many investors are wondering where to put their money, or how to recoup their losses. Against that backdrop, investors are asking how we deliver such good returns – and will that performance continue? Our goal in this annual report is to answer both of those questions.

**SHININGBANK
DISTRIBUTION RETURNS**
Versus 10-Year Canada Bonds
and 1-Year T-Bill Yield



2002 RESULTS

Cash distributions for the year totaled \$2.16 per unit, down from \$3.40 in 2001. The decrease is tied directly to a decline in natural gas prices from the phenomenal highs recorded in early 2001. This decline was partly due to the weak US economy and to the fairly warm winter at the beginning of 2002.

In the first quarter of 2002, we received an average \$3.66 per mcf, down dramatically from \$9.74 per mcf in the previous year's quarter. Natural gas prices dropped to a four-year low in the third quarter, which contributed to an average for the year of \$4.32 per mcf, down from \$5.80 per mcf for 2001. Our hedging activities helped bridge the low in prices by adding \$0.16 per mcf to our realized price, which translates to \$0.12 per unit in distributions.

Our unit price performed well, closing at \$15.15 compared with a \$13.97 close at the end of 2001. This growth is particularly notable considering that in 2002 we were in the midst of a bear equity market. The S&P/TSX Composite Index alone posted a negative 12.4% return. We view the market's support for Shiningbank as a sign of confidence in our ability to continue to consistently deliver strong investment returns.

CAN WE CONTINUE TO DELIVER SUPERIOR RETURNS?

We believe we can continue to deliver superior returns. The management team is comprised of oil and gas professionals with many years experience, and we have a definite hands-on approach to managing the Fund. We have a proven track record of capturing commodity price highs and effectively managing risk of pricing lows. The team's background is critical to managing our portfolio of properties and operations in the field – from reservoir management and maintaining low operating costs, to selecting properties that will ensure the Fund's long-term viability.

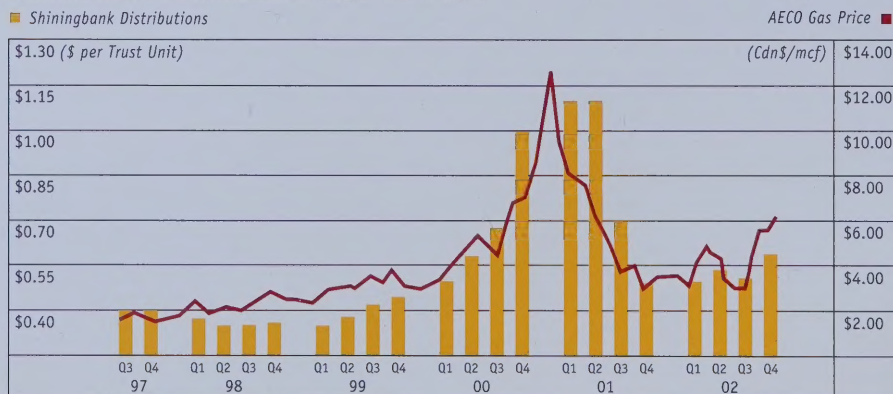
Experience aside, our cash distributions will be determined primarily by natural gas prices. As we have seen over the past few years, there can be wide swings in prices as the market responds to seasonal demand, and concerns about overall supply in North America. This price cycling will continue, but the longer-term outlook for natural gas prices remains very healthy.

Short term – For the next six months, we are likely to see strong gas prices due to the cold winter across most of North America which has drawn down natural gas supplies in storage. We have hedged about 30% of our gas volumes using price collars and fixed price contracts that guarantee at least \$5.00 per mcf, an unusually high level for the summer months.

Medium term – For the next two years, prices are expected to remain high, particularly in the winter months. This strength will be driven by lingering supply concerns and a recovery in the US economy.

Longer-term – In the next two to five years, we expect to see prices in the range of Cdn\$4.00-\$6.00 per mcf with occasional spikes above and below this range. Gas prices will continue to fluctuate, but we expect natural gas to trade in a range that will allow Shiningbank to continue to deliver strong distributions.

SHININGBANK'S DISTRIBUTIONS TRACK GAS PRICES



GROWTH IS A CHALLENGE

Shiningbank's major challenge will be to continue to grow through acquisitions. The market remains competitive, both from oil and gas companies and the growing number of trusts created in the past few years. Based on our extensive experience in the industry, we continue to be very selective about the assets we buy. Our view has always been to acquire quality assets that will benefit unitholders immediately, and provide sound value over the long term.

In 2001, our acquisition spending totaled \$310 million for property and corporate acquisitions. In 2002, that was down to \$50 million. We evaluated dozens of opportunities but, in many cases, we found prices to be too high when analyzing reserves and production against price forecasts. However, it should be noted that despite the low level of acquisitions, we added enough reserves to more than replace our 2002 production.

MAJOR ACQUISITION ANNOUNCED

Our selectivity paid off in early March 2003. As this report was being written, we announced a major acquisition of high quality assets in a core operating area in west-central Alberta. While the transaction is still subject to certain regulatory and other conditions, we expect it to close on March 28, 2003. The \$133.3 million deal will increase our production by 25%, or 3,300 boe/d comprised of 14.5 mmcf/d of natural gas and 880 bbl/d of oil and NGL. In preparation for the closing of this transaction, we have hedged most of the acquired production to lock in excellent prices.

The purchase price equates to \$11.68 per boe of established reserves. We consider this a reasonable price for the quality of the assets: long-life reserves in one of our core operating areas, NGL-rich production and low operating costs. The transaction also includes substantial undeveloped lands which provide the option of farming-out to other companies, or developing the reserves ourselves.

This announcement was in addition to three acquisitions completed in mid-January in our core operating areas with an effective date of January 1, 2003. The three transactions cost \$16.8 million and first quarter production will increase by about 815 boe/d, of which 74% is natural gas (3.6 mmcf/d).

CHANGES TO THE FUND'S STRUCTURE

Two changes were made in the structure of the Fund late last year – the internalization of management, and the change to monthly distributions from quarterly.

On October 8, 2002, unitholders overwhelming voted to restructure the Trust by internalizing the management team. By bringing all management under the Shiningbank umbrella, all management and acquisition fees have been eliminated from the Fund's cost structure. One impetus for the move was to make Shiningbank more competitive in the acquisition market. Previously, a 1.5% fee was included in all acquisition costs, which was standard practice in the trust sector. We are now able to dedicate more funding to acquiring assets, while retaining the same management team that has been in place since the start; plus their compensation is now similar to most oil and gas corporations and is more closely aligned to longer-term performance of the Fund.

At the same unitholders' meeting, a resolution was approved to allow Shiningbank to change to monthly distributions beginning with the distribution that will be paid on March 15, 2003. This change was instituted in response to many comments we received from our unitholders.



CORPORATE GOVERNANCE

The collapse of Enron, its confusing web of accounting practices and the subsequent demise of other major US corporations under a cloud of either incompetent management or greed, shocked investors and eroded confidence in North American markets. Yet it has turned the spotlight on corporate governance – how companies are run and the checks and balances in place to ensure accurate reporting and open disclosure.

It is important for unitholders to know that Shiningbank's management takes full responsibility for the Fund's financial results and our reporting to unitholders and other regulatory agencies, principally the TSX and various security exchanges. Our reporting is transparent and open, and all financial dealings appear on our statements.

Our financial statements are prepared internally, and are reviewed by the Board's Audit Committee, which is made up of three independent directors, and audited by independent auditors. Ultimately, the responsibility for our disclosure and financial statements is with management. It is an issue we take seriously, and one that has our full attention.

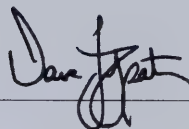
IN CLOSING

As management of the Fund, our energies will continue to be dedicated to generating superior returns for our unitholders. A good deal of activity will focus on managing distributions through the inevitable commodity price cycles: capturing pricing highs, while bridging the lows when markets are soft.

Our strategies have been fundamental to our ability to consistently deliver high distributions to unitholders, and in generating the highest compound rate of return among our peers since 1996. These strategies and our hands-on focus will continue to guide management of the Fund as we look to a strong outlook for natural gas prices.



Arne R. Nielsen
Executive Chairman



David M. Fitzpatrick
President and Chief Executive Officer

March 12, 2003



Understanding Your Investment

- ^ The Gas Market
- ^ Our Acquisition Performance
- ^ Quality Asset Base

The Gas Market

WHY WE LIKE NATURAL GAS

Natural gas has the best long-term outlook of all fossil fuels, partly because it is the most environmentally friendly.

Longer-term forecasts show demand increasing in North America, but there are concerns about supply. There is general consensus that US drilling is struggling to replace production as many of the existing basins are mature; there are fewer large reserve targets left to drill.

Other sources of natural gas are expensive and have limited potential over the medium term. These include tanker imports of liquefied natural gas (LNG) and development of Arctic reserves. About 10% of US gas production comes from seams of buried coal (coal bed methane production), and such projects are just being tested in Canada.

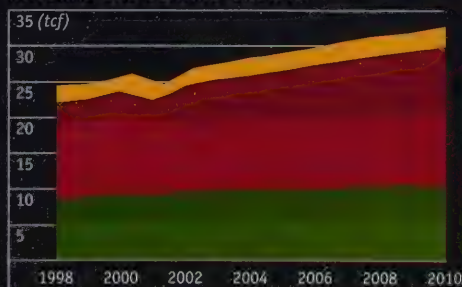
TOTAL US GAS RESERVES



■ Reserves ■ Production

Source: Natural Resources Canada

NORTH AMERICAN NATURAL GAS DEMAND GROWTH



■ Residential ■ Commercial ■ Other
■ Power Generation ■ Industrial

Source: Natural Resources Canada

Canada produces 6.4 trillion cubic feet a year, which meets 100% of domestic needs and about half is sold to US markets.



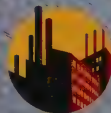
WESTERN CANADA consumes 1,450 bcf

Weak gas prices reduce money available for drilling new wells which, in turn, reduces supply.



WEST consumes 7,000 bcf

Low rainfall/snowpack depletes reservoirs needed for hydropower and utilities will switch to gas, driving up demand.



High prices force some industrial users to switch to alternate fuels such as coal or oil. This eases demand and lowers prices.

■ MAJOR GAS CONSUMING REGIONS - 2001

● MAJOR GAS SUPPLY AREAS

Main Market Drivers

Canada is the world's third largest producer of natural gas.

Exports to the US account for about 17% of US consumption.

EASTERN CANADA
consumes
1,250 bcf

MIDWEST
consumes
4,100 bcf

NORTHEAST
consumes
2,800 bcf

CENTRAL
consumes
2,550 bcf

SOUTH
ATLANTIC
consumes
1,750 bcf

GULF
consumes
5,400 bcf

Hurricanes can shut down offshore platforms and force a small price spike.



Pricing trends are set on the NYMEX exchange.

The US has over 400 underground gas storage facilities.



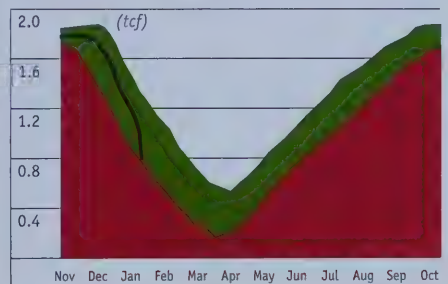
GAS IN STORAGE

The US has over 400 underground gas storage facilities, most being concentrated in the Midwest and Northeast. Gas is stored in depleted reservoirs in oil and/or gas fields; in caverns hollowed out in salt 'dome' formations; or in aquifer reservoirs which are water-only reservoirs conditioned to hold natural gas.

SUPPLY VERSUS DEMAND

Seasonal weather extremes and natural gas in storage are two key factors in the pricing equation. Storage volumes are drawn down in the peak winter heating season, and are refilled each summer. A cold winter and a low level of storage can force prices to rise dramatically. A hot summer can also cause a pricing spike as demand increases for power generation for air conditioning.

ANNUAL STORAGE PATTERN
US Gas Storage – East Region



■ 5-Year Minimum ■ 5-Year Maximum ■ 2002-2003

Source: Peters & Co. Limited

Sources:
Canadian Natural Gas: 2001 Market Review & Outlook,
Natural Resources Canada
Canadian Association of Petroleum Producers
Energy Information Administration
Peters & Co. Limited

Our Acquisition Performance

PRESERVING UNITHOLDER VALUE

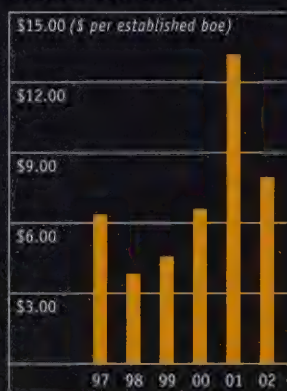
Like most royalty trusts, our growth is driven by acquisitions. In growing the Fund, and ensuring its long-term viability as a healthy investment, all acquisitions are carefully weighed for asset quality, price and operational fit with the existing asset base.

- ▲ Acquisition targets must be accretive to distributions in the short and medium term. Longer-term, assets must be acquired at a prudent cost, even when evaluated under conservative commodity price forecasts.
- ▲ In the current market of high gas prices, it is critical to buy high quality assets so properties retain their value when price cycles are lower.
- ▲ We strive to maintain a relatively flat level of value for each individual unit, which can be a challenge considering the high amount of distributable income paid to unitholders. Yet there has been growth in the Fund's net asset value per unit.

COST OF ACQUISITIONS

The past few years have seen a highly competitive market for property acquisitions, especially for high quality natural gas assets due to strong pricing forecasts. Acquisition costs in 2002 were lower than 2001 due to selective acquisitions in a competitive environment and a lack of high quality properties on the market. (See page 18 for 2002 and 2003 acquisitions).

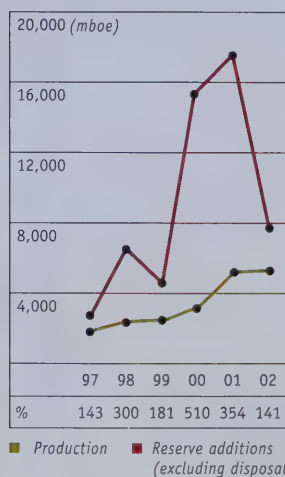
ACQUISITION COSTS



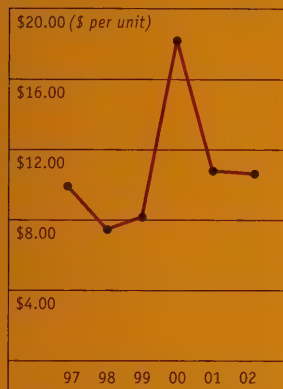
REPLACING PRODUCTION WITH NEW RESERVES

Our acquisition program has important objectives: effective reserve replacement and maintaining a healthy reserve life index. Reserve replacement refers to new reserves added each year to replace our annual production. Despite lower than usual acquisition activity in 2002, we continued to add more than enough reserves to replace production.

RESERVE REPLACEMENT



NET ASSET VALUE PER TRUST UNIT (Discounted at 10%)

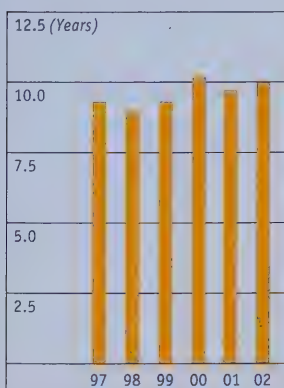


^ The spike in 2000 was due to extremely high natural gas prices.
(See page 28 for more detail).

RESERVE LIFE INDEX

The reserve life index refers to the number of years of reserves that remain if we were to produce steadily at today's level of production. Our reserve life index was 10.0 years at year-end 2002, up slightly from 9.6 years in 2001.

RESERVE LIFE INDEX

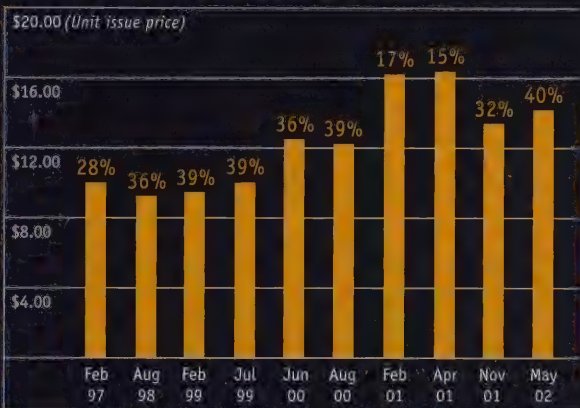


HEALTHY BALANCE SHEET

A healthy balance sheet is critical to the Fund's ability to grow. This involves maintaining a prudent level of debt, along with the regular issue of equity that ensures value to new and existing unitholders.

We have gone to the market 10 times since our initial public offering. Our investors in these secondary offerings have received total annual compound rates of return ranging from 15% to 40%. This demonstrates the strength of our strategies and our track record of delivering superior returns to unitholders.

COMPOUND ANNUAL RETURNS OF NEW ISSUES

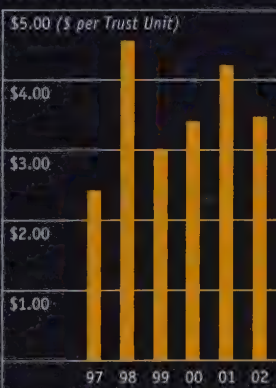


LOW DEBT LEVEL

Acquisitions are usually funded by debt. Soon after, we raise equity to pay down the cost of recent acquisitions.

The Fund's total debt per unit has ranged from \$3.47 to \$4.56 over the past five years, a level that we consider prudent use of leverage. Debt at year-end 2002 was 1.6 times fourth quarter annualized cash flow, which we consider to be both conservative and manageable.

DEBT PER TRUST UNIT



Quality Asset Base

ASSET CHARACTERISTICS

The underlying value of the Fund is based on a portfolio of high quality assets. We have assembled a portfolio of properties with specific characteristics best suited to providing unitholders with a low risk investment: a long and stable production history, a long reserve life and a low cost structure.



GEOGRAPHIC CONCENTRATION

Our assets are concentrated in west-central Alberta, which has long-life reserves, properties with a long production history, and well understood geology and reservoir performance.

The concentration of resources in one region helps reduce operating and development costs, as does the extensive network of gathering lines, processing plants and major pipelines.

HIGH QUALITY RESERVES

High quality reserves are critical to the long-term viability of the Fund. We acquire properties with a long reserve life, which helps stabilize rates of production.

86% of the Fund's established reserves are classified as proved, which means they can be economically produced using existing technology.

2002 PRODUCTION BY AREA

MOSTLY NATURAL GAS

Natural gas accounted for 75% of production, one of the highest weightings in the trust sector.

	Area	Operated	Oil (bbl/d)	Gas (mcf/d)	NGL (bbl/d)	Total Oil Equivalent (boe/d)
Alberta	Whitecourt	Yes	6	9,215	68	1,610
	Paddle River	Part	71	5,016	222	1,128
	Caroline	Yes	184	3,522	250	1,021
	St. Anne	Yes	132	3,915	–	784
	Penhold	Yes	40	3,319	158	751
	Medicine Hat	No	–	4,118	–	686
	McLeod	Part	18	2,990	93	610
	Dunvegan	No	5	2,748	135	598
	Long Coulee	Yes	387	624	3	494
	Kakut	Yes	94	2,266	21	493
	Belloy	No	3	2,199	25	395
	Virginia Hills	No	248	236	28	316
	Minehead	Yes	–	1,219	73	276
	Rosevear	Yes	–	1,352	18	243
	Swan Hills	Part	228	24	4	236
	Pembina	Yes	44	919	19	217
	Ferrier	Yes	3	1,071	34	215
	Lochend	Yes	25	732	58	204
	Other	Part	464	13,015	239	2,872
Ontario B.C.	Rodney/Innerkip	Yes	102	1,982	3	436
	Monias	Yes	–	3,759	3	629
			2,054	64,241	1,454	14,214

PRODUCTION PROFILE

75% of production is natural gas, a large portion of which is rich in NGL. The NGL is stripped out when the gas is processed and sold separately, which increases netbacks.

All oil production is light gravity and is always in demand by refineries. Light oil commands a higher price than heavier grades and takes less of a hit when oil prices are weak.

PROPERTY MIX

The asset base has a mix of mature and newer properties which aids in balancing the reserve base.

Mature properties tend to be well developed and have a long production history which reduces risk associated with production.

Newer properties have more opportunities for development through drilling of wells or other activities to improve production or reservoir performance.

LOW RISK DEVELOPMENT

We conduct low-risk development of properties, principally well workovers to improve production from individual wells.

No exploration is undertaken by Shiningbank as it entails too much risk. Occasionally, we farm-out undeveloped land to other companies; they pay for exploration and, at no cost, Shiningbank retains an interest in production from any new wells.

OPERATED PROPERTIES

In 2002, Shiningbank operated 65% of its production. Operatorship gives the Fund control over all activities including management of production volumes, reservoir performance and development. As operator, the Fund has direct control over both operating and capital costs.

2002 Operations Review

PRODUCTION

Average production increased 5% during 2002 to 14,214 boe/d, mainly through acquisitions, and the effect of a full-year of production from properties acquired in 2001. The increase was partially offset by natural declines of producing properties, which average about 12% per year, and the sale of minor properties which decreased production by about 250 boe/d.

Natural gas production grew 4% to an average 64.2 mmcf/d and made up 75% of total production. NGL associated with natural gas volumes increased 13% to 1,454 bbl/d. Crude oil was up 2% to 2,054 bbl/d.

2002 ACQUISITIONS

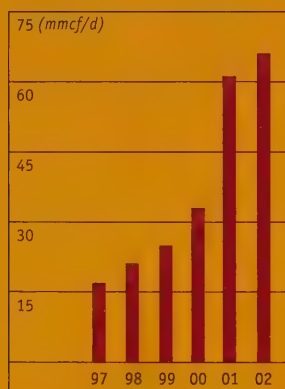
Minehead The largest acquisition completed by Shiningbank in 2002 was the \$21.1 million purchase of producing natural gas wells at Minehead, Alberta which was completed in the second quarter. This property has similar characteristics to our others in the area; long-life, NGL-rich natural gas reserves. This acquisition added 2% to our production volumes, or 276 boe/d, despite only being owned from June 1. Production from Minehead averaged 2.1 mmcf/d of natural gas and 125 bbl/d of NGL.

Mid-year acquisitions Two acquisitions were completed in late August and a third in late September. The purchases totaled \$21.3 million and were all in the vicinity of our core areas of McLeod, Caroline and Whitecourt. These transactions added approximately 4.0 mmcf/d of natural gas, and 154 bbl/d of oil and NGL production.

Fourth quarter deposits In the fourth quarter, deposits were placed on \$16.8 million of properties, and these acquisitions closed in mid-January with an effective date of January 1. We added reserves in three properties, Whitecourt, Modeste Creek and Long Coulee, which are in or near existing operations. The three transactions will increase first quarter production by about 815 boe/d, of which 74% is natural gas (3.6 mmcf/d). These acquisitions are included in our 2002 year-end reserve figures presented in this report, and associated costs have been included in our acquisition and development costs.

Acquisition and development costs Acquisition costs in 2002 amounted to \$7.94 per established boe, down from \$13.21 per boe in 2001 and lower than the five-year average of \$8.82 per boe. The lower cost was due, in part, to a relatively low level of activity during the year. The price of properties, particularly natural gas assets, has climbed substantially in recent years. In 2002, despite relatively low commodity prices, acquisition prices were generally higher than we were willing to pay for the quality of assets for sale. We believe it is important to ensure that only high quality properties are purchased, which minimizes the financial impact in the event that commodity prices are below normal for a period of time.

AVERAGE DAILY
NATURAL GAS PRODUCTION



Costs Per Boe of Established Reserves

	2000	2001	2002	Five-year average
Acquisition costs	\$ 6.61	\$ 13.21	\$ 7.94	\$ 8.82
Development costs	6.62	17.94	13.27	10.20
Total acquisition and development	6.61	13.40	9.86	8.91
Operating netback per boe	\$ 22.43	\$ 20.92	\$ 16.31	\$ 16.77
Recycle ratio (<i>Netback ÷ acquisition and development costs</i>)	3.4	1.6	1.7	1.9
Reserve replacement (<i>% of production</i>)	510%	354%	141%	275%

Development costs A total of \$11.9 million was spent in 2002 on drilling and other development activities. A total of 239 gross (18.0 net) wells were drilled, completed and tied-in at a cost of \$4.1 million, with a success rate of 100%. These new wells added 894,000 boe of established reserves for a development cost of \$4.59 per boe.

An additional \$7.8 million was spent on upgrading existing production and well facilities, accelerating production volumes and minor land purchases. These costs will contribute to lower operating expenses in the future.

Recycle ratio The total acquisition and development cost was \$9.86 per established boe. With our 2002 operating netback of \$16.31 per boe, the annual recycle ratio was 1.7 times. This was below our target recycle ratio of 2.0 times due to the effect of lower commodity prices, which reduced our netback for the year. Using a fourth quarter netback of \$19.86 per boe, our recycle ratio rises to 2.0 times and is more indicative of the current environment.

SUBSEQUENT TO YEAR END

Major core area acquisition In early March 2003, we announced a \$133.3 million acquisition of high quality producing properties which will increase our production by 25%, or 3,300 boe/d. The production is 73% natural gas, or 14.5 mmcf/d, and 880 bbl/d of oil and NGL. The transaction is subject to certain regulatory and other conditions, but is expected to close March 28.

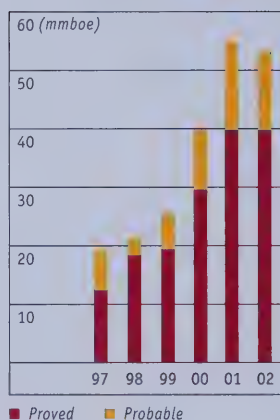
This major acquisition was particularly attractive for the high quality of the assets. The deal involves a package of properties, 70% to be operated by Shiningbank, in the Ferrier and O'Chiese areas of west-central Alberta, adjacent to our existing operations at Ferrier. The properties are characterized by long-life, NGL-rich gas production combined with low operating costs. We retained independent engineers to evaluate the reserves and they have assigned a reserve life index of 9.5 years to the established reserves. Our established natural gas reserves will increase by 24%, or 49.6 bcf. The cost of the acquisition equates to \$11.68 per established boe, which we consider an attractive price when considering the quality of the properties against natural gas price forecasts.

RESERVES

Our year-end reserves were evaluated by the independent engineering firm, Paddock Lindstrom & Associates Ltd. Established reserves (proved plus 50% probable) were essentially the same as at the end of 2001. Our 2002 acquisition and development activity offset production, minor dispositions and reserve revisions.

The value of the reserve base grew by 13%, due mainly to higher forecasted commodity prices. Proved producing reserves made up 86% of total proved reserves and 74% of the established reserves. The reserve life index for established reserves stood at 10 years.

TOTAL RESERVES



Reserve Reconciliation

	Oil and NGL (mmbbl)			Natural Gas (bcf)			Barrels of Oil Equivalent 6:1 (mboe)		
	Proved	Risked Probable	Established	Proved	Risked Probable	Established	Proved	Risked Probable	Established
December 31, 2001	10,070	1,974	12,044	181.7	29.1	210.8	40,351	6,820	47,171
Acquisitions	1,726	180	1,906	32.9	4.0	36.9	7,208	836	8,044
Disposals	(689)	(346)	(1,035)	(7.5)	(0.8)	(8.3)	(1,936)	(483)	(2,419)
Development	113	27	140	4.2	0.3	4.5	812	82	894
Revisions	241	(123)	118	(6.6)	(3.9)	(10.5)	(848)	(764)	(1,612)
Production	(1,280)	—	(1,280)	(23.4)	—	(23.4)	(5,188)	—	(5,188)
December 31, 2002	10,181	1,712	11,893	181.3	28.7	210.0	40,399	6,491	46,890

Value of Reserves Using Escalated Prices

(000s)	Discount factor			
	0%	10%	12%	15%
Proved	\$ 739,888	\$ 437,170	\$ 407,087	\$ 370,050
Risked Probable	114,538	45,192	39,839	33,629
Established	\$ 854,426	\$ 482,362	\$ 446,926	\$ 403,679

Escalating Price Assumptions

Year	Crude Oil		Natural Gas	Exchange Rate
	West Texas Intermediate US\$/bbl	Edmonton Light Crude Cdn\$/bbl	Alberta Reference Price Cdn\$/mmbtu	Foreign Exchange US\$/Cdn\$
2003	\$ 26.00	\$ 38.96	\$ 5.25	\$ 0.65
2004	24.00	35.86	4.91	0.65
2005	22.50	33.53	4.64	0.65
2006	22.95	34.20	4.76	0.65
2007	23.41	34.89	4.81	0.65

Management's Discussion and Analysis

Boe volumes are reported at 6:1 with 6 mcf = 1 bbl.

Results of Operations

PRODUCTION VOLUMES

Daily Production Volumes

	2002	2001	% change
Oil (bbl/d)	2,054	2,013	2%
Natural gas (mmcf/d)	64.2	61.6	4%
NGL (bbl/d)	1,454	1,288	13%
Oil equivalent (boe/d)	14,214	13,564	5%
Natural gas % of total production	75%	76%	

Average daily production volumes grew 5% during 2002, mainly as a result of production added through acquisitions and the full-year effect of production acquired in 2001. Significant acquisitions in 2002 were of producing properties in or near our existing core central Alberta production areas of Minehead, McLeod and Whitecourt. These production increases were partly offset by natural declines of producing properties, which are estimated to average 12% per year and sales of minor properties which contributed approximately 250 boe/d to the decline.

PRICING – AFTER HEDGING

Average Prices – After Hedging

	2002	2001	% change
Oil (Cdn\$/bbl)	36.31	35.67	2%
Natural gas (Cdn\$/mcf)	4.32	5.80	(26)%
NGL (Cdn\$/bbl)	26.59	29.59	(10)%
Oil equivalent (Cdn\$/boe)	27.50	34.48	(20)%
WTI (US\$/bbl)	26.08	25.94	1%
AECO natural gas (Cdn\$/mcf)	4.07	6.30	(35)%

Shiningbank's realized natural gas prices averaged \$4.32/mcf, 26% lower than last year. Benchmark prices in Alberta (AECO) fell by 35% on average from 2001. While prices were lower than in 2000 and 2001, it appears that market forces will sustain higher average prices for at least the next year. While US industrial demand is down substantially with a weakened economy, supply concerns have continued to drive prices upward this winter. At the start of the 2002/03 winter, volumes in storage were at an all-time high. However, frigid temperatures in much of North America led to storage being drawn down to very low levels – and spot prices peaked at above \$13.00/mcf in late February 2003. Such high prices tend to weaken demand as some industrial users switch to less costly fuels. However, supply concerns are continuing to dominate the market. As a result, Shiningbank expects higher prices in 2003 as large volumes will be required to refill storage this summer, and into next winter's prime demand heating season.

Oil prices averaged \$36.31/bbl, 2% higher than 2001. Benchmark West Texas Intermediate oil averaged US\$26.08/bbl for 2002, 1% higher than 2001's average of US\$25.94/bbl. The situation in Iraq and Venezuela added a substantial premium to prices in the fourth quarter and increased the average for the year. This premium has continued into 2003, but may disappear quickly when tensions ease, resulting in prices returning to the more normal range of US\$20 to US\$25/bbl.

HEDGING POLICY AND RESULTS

Shiningbank maintains an active hedging program for both oil and gas production. During 2002, the Fund hedged an average of 20.3 mmcf/d of natural gas (30% of total gas production), and 500 bbl/d of oil production (24% of total oil production). Under the Fund's hedging policy, not more than one-half of production volumes can be hedged at any one time. Hedging is intended to stabilize cash distribution levels by fixing the price on a portion of the production portfolio. Hedging activity in 2002 added \$3.8 million to revenues, increasing the realized natural gas price by \$0.16/mcf and reducing the oil price by \$0.08/bbl.

Current Hedging Activity

Period	Commodity	Volume	Price
November 1, 2002 – October 31, 2003	Gas	2 mmcf/d	\$4.22/mcf floor \$8.70/mcf ceiling
November 1, 2002 – March 31, 2003	Gas	5 mmcf/d	\$4.22/mcf floor \$7.69/mcf ceiling
November 1, 2002 – March 31, 2003	Gas	5 mmcf/d	\$4.74/mcf floor \$7.52/mcf ceiling
April 1, 2003 – October 31, 2003	Gas	5 mmcf/d	\$5.38/mcf
April 1, 2003 – October 31, 2003	Gas	5 mmcf/d	\$5.01/mcf floor \$7.06/mcf ceiling
April 1, 2003 – October 31, 2003	Gas	5 mmcf/d	\$5.27/mcf floor \$8.43/mcf ceiling
April 1, 2003 – December 31, 2003	Gas	13 mmcf/d	\$7.75/mcf
January 1, 2004 – December 31, 2004	Gas	11 mmcf/d	\$6.44/mcf
January 1, 2003 – December 31, 2003	Oil	500 bbl/d	US\$24.00/bbl floor US\$27.62/bbl ceiling
July 1, 2003 – December 31, 2003	Oil	500 bbl/d	US\$26.00/bbl floor US\$30.10/bbl ceiling



REVENUES

(000s)	2002	%	2001	%
Oil sales	\$ 27,276	19%	\$ 25,805	15%
Natural gas sales	97,476	68%	128,373	75%
NGL sales	14,106	10%	13,914	8%
Hedging	3,761	3%	2,483	2%
Other	42	–	139	–
	\$ 142,661	100%	\$ 170,714	100%

Sales Variance Analysis - Before Hedging

(000s)	Crude oil and NGL 2002/2001	Natural gas 2002/2001
Volume increase	\$ 2,471	\$ 5,558
Price increase (decrease)	(808)	(36,455)
Net increase	\$ 1,663	\$ (30,897)

Lower revenues in 2002 resulted primarily from lower natural gas prices offset, in part, by higher volumes of both oil and natural gas.

ROYALTIES

	2002	2001	% change
Total royalties, net (000s)	\$ 26,470	\$ 38,857	(32)%
As % of revenue	18.6%	22.8%	(18)%
Per boe	\$ 5.10	\$ 7.85	(35)%

Royalty expense consists of royalties paid to provincial governments, freehold landowners and overriding royalty owners. The royalty rate was lower in 2002 mainly due to lower commodity prices under the price-sensitive rate structure for Alberta Crown natural gas royalties. It is expected that higher commodity prices in 2003 will result in a slightly higher royalty rate. The Alberta government provides a credit under the Alberta Royalty Credit program, which the Fund is eligible to access on a small portion of its properties. The Fund recorded the maximum \$500,000 in Alberta Royalty Credit in each of 2002 and 2001.

OPERATING COSTS

	2002	2001	% change
Operating costs (000s)	\$ 31,583	\$ 28,257	12%
Per boe	\$ 6.09	\$ 5.71	7%

Operating costs increased by 7% on a boe basis for 2002, due mainly to higher operating costs associated with acquired properties and generally higher field costs. Continued upward pressure on field costs, ageing of the property portfolio and the likelihood of higher energy costs in 2003 are expected to offset any efficiencies gained in the Fund's operations, leaving 2003 per boe costs similar to those in 2002.

GENERAL AND ADMINISTRATIVE COSTS

	2002	2001	% change
General and administrative costs (000s)	\$ 4,143	\$ 3,788	9%
Per boe	\$ 0.80	\$ 0.77	4%
Per Trust Unit	\$ 0.13	\$ 0.16	(19)%

General and administrative costs increased 9% over 2001 due to the growth in the asset base from acquisitions. At year end, Shiningbank had 30 full-time employees and 17 full- and part-time consultants at its head office. Field and production staff consisted of one production superintendent, 19 full-time employees and 36 contract operators. Costs of field and production staff are included in operating expenses.

MANAGEMENT FEES

	2002	2001	% change
Management fees (000s)	\$ 1,939	\$ 3,500	(45)%
Per boe	\$ 0.37	\$ 0.71	(48)%
Per Trust Unit	\$ 0.06	\$ 0.15	(60)%

Management fees declined 45% in 2002 due to lower operating income and the internalization transaction which eliminated all management and acquisition fees after October 9, 2002. In 2003 and into the future, no management fees will be charged.

INTEREST

	2002	2001	% change
Interest (000s)	\$ 5,109	\$ 5,675	(10)%
Per boe	\$ 0.98	\$ 1.15	(15)%
Per Trust Unit	\$ 0.16	\$ 0.24	(33)%

Interest expense decreased 10% during 2002 due to lower interest rates and debt levels. Rising inflation rates in early 2003 are expected to increase interest rates on average. Total interest costs for the Fund are also affected by acquisition activity and new equity issues which raise and lower debt levels, respectively.

DEPRECIATION, DEPLETION AND AMORTIZATION

	2002	2001	% change
Depreciation, depletion and amortization (000s)	\$ 60,034	\$ 47,032	28%
Per boe	\$ 11.57	\$ 9.50	22%

Depreciation, depletion and amortization rose 28% from 2001 as a result of higher production volumes and a higher rate per boe. Per boe costs were up due to higher-priced acquisitions over the last several years, primarily in 2001.

INTERNALIZATION OF MANAGEMENT CONTRACT

	2002	2001
Internalization of management contract (000s)	\$ 10,984	\$ -
Per boe	\$ 2.12	\$ -

Effective October 9, 2002, the Fund internalized its management by acquiring all of the shares of Shiningbank Energy Management Inc. Prior to the acquisition, the Fund paid fees of 3.25% of net operating income, a fee of 1.5% on the purchase price of acquisitions and a quarterly scheduled dividend in accordance with the terms of the management agreement. The acquisition resulted in the elimination of all future fees and dividends.

Of the total purchase price of \$20.6 million, \$2.9 million was paid in cash consideration, \$1.2 million was paid in costs of the transaction, and \$16.5 million was paid in Exchangeable Shares which are subject to certain escrow provisions. \$10.0 million of the total purchase price was deferred representing Exchangeable Shares subject to escrow provisions and will be amortized into income over the specific vesting periods from 2003 to 2007. For the year ended December 31, 2002, \$978,000 was recorded as expense representing the amortization of these escrowed Exchangeable Shares. Total consideration was reduced by \$1.8 million to provide for performance/retention bonuses to be paid to employees over five years, of which \$400,000 was paid in 2002.

TAXES

(000s)	2002	2001	% change
Capital and large corporations taxes	\$ 665	\$ 384	73%
Future income tax recovery	\$ (14,160)	\$ (9,900)	49%

The Fund is obliged to pay provincial capital taxes and federal large corporations tax in its operating corporations but manages its activities so as not to pay current income taxes in those entities.

Future income taxes are recorded on corporate acquisitions to the extent that the book value of assets acquired exceeds the tax basis. These future income taxes increase the book cost of the acquired assets. It is expected that future income taxes will be recovered over time as royalties are paid to the Fund. In 2002, the Fund recorded a recovery of future income taxes of \$14.2 million resulting from changes in temporary differences and a reduction in the Alberta corporate income tax rate, leaving a balance of \$63.3 million in future income taxes payable at December 31, 2002.

NET EARNINGS

Shiningbank's net earnings were \$13.0 million or \$0.40 per Trust Unit (\$0.08 diluted) in 2002 compared with \$50.7 million or \$2.08 per Trust Unit (\$2.08 diluted) in 2001. Lower natural gas & NGL prices and higher costs and expenses associated with the internalization of the management contract were partly offset by higher production levels.

DISTRIBUTABLE INCOME

Distributable income for 2002 decreased to \$69.6 million from \$82.0 million in 2001 due to lower natural gas and NGL prices and higher costs. On a per Trust Unit basis, distributions decreased 36% to \$2.16 from \$3.40 in 2001. Distributions in 2003 are expected to strengthen based on stronger commodity price levels. The sensitivity of distributions to commodity price variables is shown in the table below.

Calculation of Distributable Income

<i>(000s, except Trust Unit amounts)</i>	2002	2001
Cash flow from operating activities	\$ 68,243	\$ 90,253
Capital expenditures	(11,867)	(4,328)
Site restoration costs	(385)	(491)
Internalization of management contract	4,509	—
Working capital adjustments	9,107	(3,455)
Distributable income	\$ 69,607	\$ 81,979
Distributions per Trust Unit	\$ 2.16	\$ 3.40
Trust Units outstanding <i>(000s)</i>	33,194	29,118

Per Boe Revenue and Expense Analysis

	2002	2001
Daily production <i>(boe/d)</i>	14,214	13,564
Gross revenue	\$ 27.50	\$ 34.48
Royalties	(5.10)	(7.85)
Operating costs	(6.09)	(5.71)
Operating netback	16.31	20.92
General and administrative	(0.80)	(0.77)
Management fees	(0.37)	(0.71)
Interest on long term debt	(0.98)	(1.15)
Capital expenditures and site restoration	(2.36)	(0.97)
Capital and large corporations taxes	(0.13)	(0.08)
Working capital adjustments and other	1.75	(0.68)
Distributable income per boe	\$ 13.42	\$ 16.56

2003 Distributable Income Sensitivities

	<i>(\$000s)</i>	Per Trust Unit
US \$1 per bbl	1,200	\$ 0.03
Cdn \$0.25 per mcf	4,100	\$ 0.11
US \$0.01 exchange	1,900	\$ 0.05
100 bbl/d	800	\$ 0.02
1 mmcf/d	1,500	\$ 0.04
1% prime rate	900	\$ 0.02

Note: These sensitivities take into account the issue of 3,841,000 new Trust Units in February 2003.



INCOME TAX INFORMATION

In 2002, 64.2% of distributions payable by the Fund were required to be included in the income of unitholders. The balance of the distributions reduced each unitholder's adjusted cost base in their Trust Units for income tax purposes.

Summary of Distributions and Taxability

	Record date	Payment date	Distribution (\$ per unit)	Taxable portion (\$ per unit)	ACB reduction (\$ per unit)
1996	September 30	October 15	\$ 0.4070	\$ –	\$ 0.4070
	December 31	January 15, 1997	\$ 0.4200	\$ –	\$ 0.4200
1997	March 31	April 15	\$ 0.4000	\$ –	\$ 0.4000
	June 30	July 15	\$ 0.4000	\$ –	\$ 0.4000
	September 30	October 15	\$ 0.4000	\$ –	\$ 0.4000
	December 31	January 15, 1998	\$ 0.4000	\$ 0.0575	\$ 0.3425
1998	March 31	April 15	\$ 0.3700	\$ 0.0532	\$ 0.3168
	June 30	July 15	\$ 0.3500	\$ 0.0503	\$ 0.2997
	September 30	October 15	\$ 0.3500	\$ 0.0503	\$ 0.2997
	December 31	January 15, 1999	\$ 0.3600	\$ 0.1050	\$ 0.2550
1999	March 31	April 15	\$ 0.3500	\$ 0.1021	\$ 0.2479
	June 30	July 15	\$ 0.3800	\$ 0.1109	\$ 0.2691
	September 30	October 15	\$ 0.4200	\$ 0.1226	\$ 0.2974
	December 31	January 15, 2000	\$ 0.4500	\$ 0.2270	\$ 0.2230
2000	March 31	April 15	\$ 0.5000	\$ 0.2522	\$ 0.2478
	June 30	July 15	\$ 0.5800	\$ 0.2926	\$ 0.2874
	September 30	October 15	\$ 0.6800	\$ 0.3430	\$ 0.3370
	December 31	January 15, 2001	\$ 1.0000	\$ 0.7478	\$ 0.2522
2001	March 31	April 15	\$ 1.1000	\$ 0.8226	\$ 0.2774
	June 30	July 15	\$ 1.1000	\$ 0.8226	\$ 0.2774
	September 30	October 15	\$ 0.7000	\$ 0.5235	\$ 0.1765
	December 31	January 15, 2002	\$ 0.5000	\$ 0.3210	\$ 0.1790
2002	March 31	April 15	\$ 0.5000	\$ 0.3210	\$ 0.1790
	June 30	July 15	\$ 0.5400	\$ 0.3467	\$ 0.1933
	September 30	October 15	\$ 0.5200	\$ 0.3338	\$ 0.1862
	December 31	January 15, 2003	\$ 0.6000	Available in 2004	

COSTS OF ACQUISITIONS AND DEVELOPMENT

In 2002, Shiningbank acquired a total of \$50 million in new properties in 16 separate asset purchases. The most significant acquisitions were at Minehead, McLeod and Whitecourt. The Fund disposed of non-core properties in 22 transactions for total proceeds of \$11.4 million. Costs of drilling and new facilities totaled \$11.9 million. Shiningbank's combined acquisition and development costs were \$9.86 per boe of established reserves.

NET ASSET VALUE

(000s)	Discount factor		
	10%	12%	15%
Present value of reserves			
Proved	\$ 437,170	\$ 407,087	\$ 370,050
Risky probable	45,192	39,839	33,628
Undeveloped lands	8,500	8,500	8,500
Working capital (deficit)	(14,386)	(14,386)	(14,386)
Total assets	476,476	441,040	397,792
Long term debt	(130,301)	(130,301)	(130,301)
Net asset value	\$ 346,175	\$ 310,739	\$ 267,491
Trust Units outstanding (000s)	33,194	33,194	33,194
Net asset value per Trust Unit			
At December 31, 2002	\$ 10.43	\$ 9.36	\$ 8.06
At December 31, 2001	\$ 10.78	\$ 9.60	\$ 8.18

Notes:

1. The present value of reserves is calculated based on price forecasts prepared by Paddock Lindstrom & Associates Ltd. in its December 31, 2002 evaluation.
2. Reserve values and long term debt reflect the acquisition of properties effective January 1, 2003, but which had not yet closed at December 31, 2002.

QUARTERLY FINANCIAL INFORMATION

(000s, except per Trust Unit amounts)		March 31	June 30	Sept 30	Dec 31
2002	Oil and natural gas sales	\$ 29,823	\$ 36,804	\$ 33,918	\$ 42,116
	Net earnings (loss)	2,982	7,061	5,061	(2,072)
	Per Trust Unit – basic	0.10	0.22	0.15	(0.06)
	Per Trust Unit – diluted	0.10	0.22	0.15	(0.35)
	Distributions	14,559	17,897	17,234	19,917
	Per Trust Unit	0.50	0.54	0.52	0.60
2001	Oil and natural gas sales	\$ 45,070	\$ 53,472	\$ 40,377	\$ 31,795
	Net earnings	20,060	20,431	8,519	1,641
	Per Trust Unit – basic	1.07	0.83	0.33	0.05
	Per Trust Unit – diluted	1.06	0.83	0.33	0.05
	Distributions	21,728	27,410	18,282	14,559
	Per Trust Unit	1.10	1.10	0.70	0.50

Liquidity and Capital Resources

LONG TERM DEBT

Shiningbank maintains a revolving committed line of credit with a syndicate of four Canadian chartered banks with a committed amount of \$170 million and a borrowing base at year end of \$160 million reducing to \$155 million on January 1, 2003. At December 31, 2002, \$115.3 million was drawn. Under the terms of the credit agreement, the revolving period ends on April 30, 2003, however, it is expected that the revolving period will be extended until at least the end of 2003. During 2002, the Fund decreased the total amount drawn on its credit lines by \$7.2 million.

The Fund's governing documents restrict debt levels to 40% of the value of its properties, and debt service costs are not to exceed 30% of the projected annual cash flow. Neither of these limits was being approached at December 31, 2002.

FUTURE INCOME TAXES

Over the course of the year, the Fund recovered \$14.2 million of the future income tax liability. As a result, future income taxes stood at \$63.3 million at December 31, 2002.

UNITHOLDERS' EQUITY

In May 2002, the Fund issued 4,025,000 new Trust Units at \$14.20 each for gross proceeds of \$57.2 million. These funds reduced debt resulting from previous acquisitions.

On October 9, 2002, the Fund acquired all of the outstanding shares of Shiningbank Energy Management Inc., the former Manager of the Fund. As part of the consideration for the transaction, 1,136,614 Exchangeable Shares were issued, of which 757,742 were held in escrow to be released over periods of three to five years. These shares may be exchanged for Trust Units of the Fund at the discretion of the holders. The exchange rate was initially one Trust Unit for each Exchangeable Share. The exchange rate increases with each distribution by the Trust by an amount equal to the per unit distribution divided by the 10-day weighted average trading price of the Trust Units preceding the record date for that distribution. The Exchangeable Shares are not eligible for distributions.

On February 11, 2003, the Fund closed the issue of 3,841,000 Trust Units at a price of \$15.00 each for gross proceeds of \$57.6 million.

Business Risks

Shiningbank is faced with a number of business risks that are inherent in the oil and gas business, and which can have a material impact on distributions to unitholders. To mitigate these risks, the Fund employs policies and appropriate procedures in its day-to-day operations and in its longer-term planning.

MARKET RISKS

Commodity prices

The primary risk to cash flow and therefore, distributions, is fluctuations in oil and gas prices. With Shiningbank's production weighted 75% to natural gas, changes in natural gas markets and pricing are the primary driver behind the level of distributions.

- ▲ To mitigate price risk, the Fund actively manages the sales of its production to maximize pricing and volumes.
- ▲ The Fund has an active hedging program through which management attempts to minimize the effect of commodity price drops in the short run, while retaining exposure to upward price changes. This is accomplished by use of simple hedging instruments, primarily “costless collars” and fixed price swaps.
- ▲ Costless collars provide a minimum price, or “floor,” on a specific volume of oil or gas for a specified time. The cost of this “floor” is paid for by capping the upward movement of prices with a “ceiling” price for the same volume and time frame. A list of currently active hedges is set out in Note 8 to the Consolidated Financial Statements.
- ▲ Shiningbank's hedging practices are not designed to have a material impact on the medium and long-term effects of commodity prices on distributions to unitholders. Unitholders remain exposed to such price fluctuations over time.
- ▲ Under the Fund's hedging policy, not more than 50% of production volumes can be hedged at any one time.
- ▲ Hedging is employed only as a risk management tool to stabilize distributions and not for speculation.

Interest rates

Shiningbank is exposed to changes in interest rates, although the Fund's distributions are affected to a lesser degree than changes in commodity prices.

- ▲ The Fund's governing documents restrict debt levels to 40% of the value of its properties, and debt service costs are not to exceed 30% of the projected annual cash flow.
- ▲ The Fund has a line of credit that bears interest at market rates and which is reviewed regularly by its lenders.
- ▲ This debt bears interest at current short-term market rates, apart from \$10 million of the debt for which the rate has been fixed through an interest rate swap until October 2004.

Currency rates

Exposure to currency exchange risk arises from the fact that oil and, to a lesser degree, natural gas are priced in international markets and, primarily, in US dollars. As a result, the amount received by Shiningbank may be dependent on the strength of the Canadian dollar versus the US dollar.

- ▲ Shiningbank has the ability to hedge its currency exposure to reduce the impact of a weak Canadian dollar.
- ▲ The Fund has no currently active hedges of this type.

FINANCIAL RISKS

Shiningbank's ability to grow is contingent upon its ability to raise debt and equity capital in the Canadian financial markets.

Debt

The Fund has lines of credit held by four Canadian chartered banks, which provide sufficient debt capital to satisfy the Fund's needs to do most acquisitions.

- ▲ Use of debt capital to acquire assets is generally accretive to unitholder distributions and asset value due to the cost of debt financing when compared to the cost of assets.

Equity

Periodically, the Fund accesses the Canadian equity markets to issue new Trust Units. Amounts raised in this fashion are used to pay down debt accumulated from previous acquisitions.

- ▲ The issue of new equity allows the Fund to pay down debt while continuing to grow through acquisitions.
- ▲ Such issues only dilute existing unitholders when equity is issued without a corresponding acquisition.
- ▲ If the Canadian equity or debt markets were to become unable to satisfy the funding needs of Shiningbank's growth, it may impair the ability of the Fund to continue to replace production and maintain distributions.

POLITICAL AND LEGAL RISKS

Shiningbank's activities are affected by the political and legal environment in which it operates. Some examples of these uncertainties include:

- ▲ Changes in securities regulations which may affect the Fund's ability or cost structure related to raising additional equity or debt capital;
- ▲ Changes in environmental regulations which may increase the cost of operating oil and gas producing properties;
- ▲ Changes in income tax laws which may affect either tax costs to the Fund or to its unitholders;
- ▲ Changes in provincial Crown royalty regulation and compliance; and
- ▲ Changes in law which affect the prices or ownership of oil and gas reserves and production.

Kyoto Accord

It is unclear what impact the Kyoto Accord will have on Shiningbank's distributions, the Canadian oil and gas industry, or Canada's economy as a whole. Until the Accord is ratified by other countries, it is unclear how it will be applied internationally and, even within Canada, the federal government has yet to make public how it intends to fully achieve its Kyoto objectives, or the effects it will have on specific industries and companies.

- ▲ Based on Shiningbank's evaluation of publicly available information, we believe that there will be no material impact on Shiningbank.
- ▲ It is possible that if the rules, when issued, increase the attractiveness of cleaner burning fossil fuels such as natural gas, the Accord may have a positive effect on the Fund due to its natural gas concentration.

Unitholders' liability

There has recently been discussion in the media about the lack of statutory protection for unitholders in mutual fund trusts such as Shiningbank and its competitors.

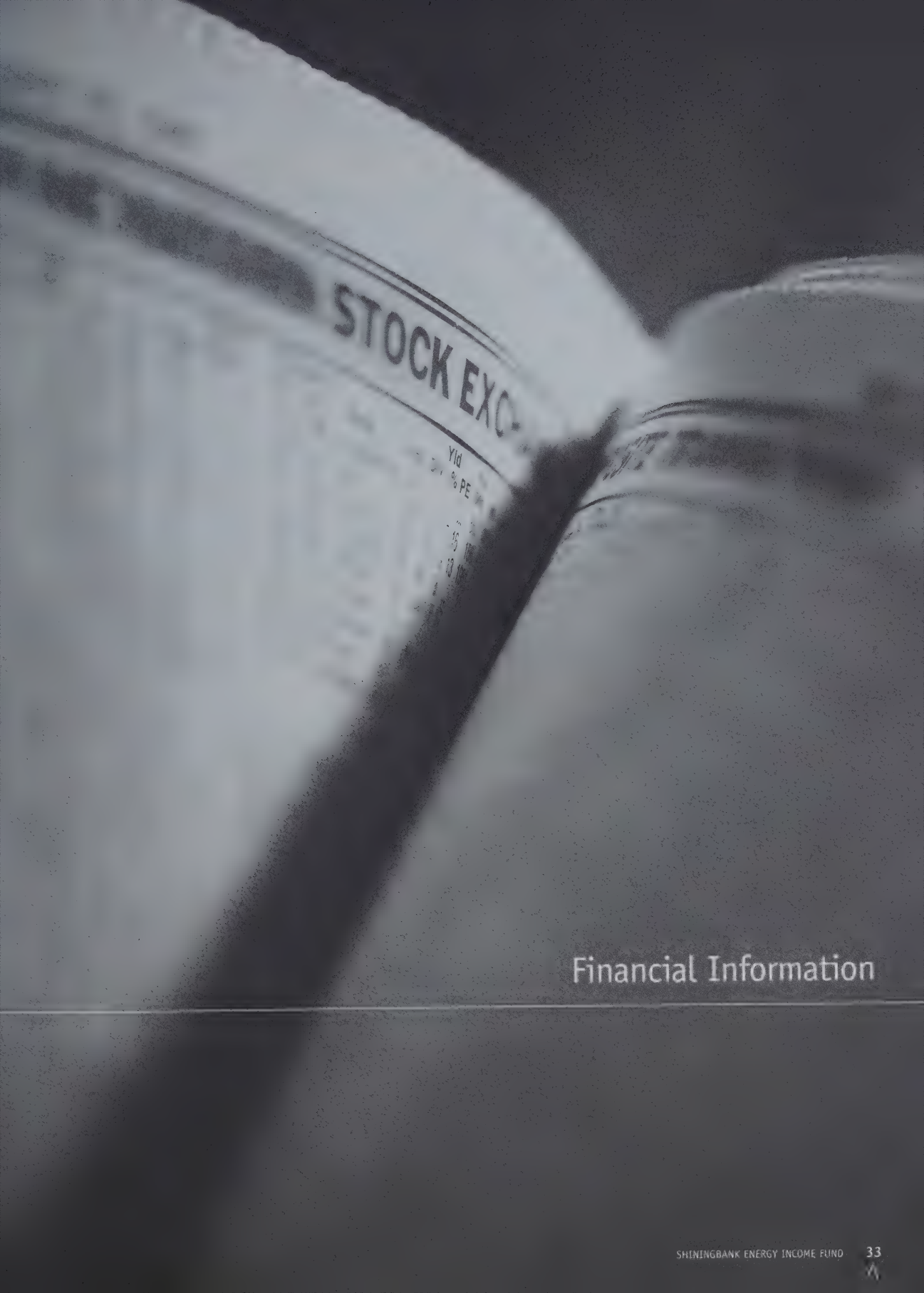
- ▲ Canadian laws provide a statutory limit on liability of shareholders in corporations, limiting their liability to their investment in the corporation. This limit is not set out by statute in respect of individual holders of units in trusts.
- ▲ Unitholders in Shiningbank are shielded from such liability through the structure of the Trust, which uses corporate entities to hold all producing assets and to employ staff.
- ▲ Substantial insurance coverage is maintained at all times protecting against exposure to liability.
- ▲ Significant efforts are underway by industry to lobby provincial governments to extend statutory limited liability to unitholders of all publicly held trusts. Nevertheless, despite the lack of specific statutory limitation of unitholder liability, it is management's view that the exposure to unitholders is extremely small.

Operating Risks

FIELD OPERATIONS

Oil and gas production activities carry a number of inherent risks including production risks relating to the ability to produce and process crude oil and natural gas from existing wells; the ability to develop or acquire sufficient quantities of crude oil and natural gas to replace production and maintain reserves; risks of environmental damage; and risks to the safety of its employees, contractors and the public.

- ▲ To mitigate these risks, the Fund maintains financial flexibility to ensure its ability to ensure efficient operations in the field.
- ▲ The Fund employs skilled personnel, both in the field and in its head office, and ensures that they are equipped with efficient and effective tools and training.
- ▲ Shiningbank maintains insurance coverage in order to minimize the impact of events that might cause substantial financial damage.
- ▲ Shiningbank's strategy of operating a significant portion of its production provides greater control over operational factors, including ensuring properties are operated in accordance with its policy to minimize impacts on the environment.



STOCK EXCHANGE

Yld

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Financial Information

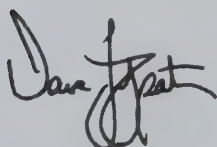
Management's Report

Management is responsible for the integrity and objectivity of the information contained in this annual report and for the consistency between the financial statements and other financial operating data contained elsewhere in the report. The accompanying financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada using estimates and careful judgement, particularly in those circumstances where transactions affecting a current period are dependent upon future events. The accompanying financial statements have been prepared using policies and procedures established by management and reflect fairly the Fund's financial position, results of operations and cash flow, within reasonable limits of materiality and within the framework of the accounting policies as outlined in the notes to the financial statements.

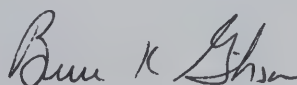
Management has established and maintained a system of internal control which is designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and the financial information is reliable and accurate.

The financial statements have been examined by external auditors. Their examination provides an independent view as to management's discharge of its responsibilities insofar as they relate to the fairness of reported operating results and financial condition of the Fund.

The Audit Committee of the Board of Directors has reviewed in detail the financial statements with management and the external auditors. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.



David M. Fitzpatrick
*President &
Chief Executive Officer*



Bruce K. Gibson
*Vice President,
Finance & Chief Financial Officer*

Auditors' Report

To the Unitholders of Shiningbank Energy Income Fund

We have audited the consolidated balance sheets of Shiningbank Energy Income Fund as at December 31, 2002 and 2001 and the consolidated statements of earnings and unitholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2002 and 2001 and the results of its operations and its cash flow for the years then ended in accordance with Canadian generally accepted accounting principles.



*Chartered Accountants
Calgary, Canada*

March 12, 2003

Consolidated Balance Sheets

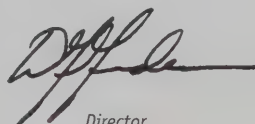
December 31 (\$ thousands)	2002	2001
ASSETS		
Current assets		
Accounts receivable	\$ 23,637	\$ 24,142
Prepaid expenses	2,878	3,430
	26,515	27,572
Fixed assets (note 3)		
Petroleum and natural gas properties and equipment	631,204	579,530
Accumulated depreciation and depletion	(165,668)	(105,867)
	465,536	473,663
Other assets	2,252	1,830
	\$ 494,303	\$ 503,065
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable	\$ 20,985	\$ 20,352
Trust Unit distribution payable	19,916	14,559
	40,901	34,911
Long term debt (note 4)	115,283	122,459
Future income taxes (note 6)	63,340	77,500
Provision for future site restoration	8,347	5,870
Unitholders' equity		
Trust Units (note 5)	391,970	337,246
Exchangeable Shares (note 5)	6,475	-
Accumulated income	107,302	94,787
Accumulated royalty distributions	(239,315)	(169,708)
	266,432	262,325
	\$ 494,303	\$ 503,065

See accompanying notes to consolidated financial statements

Approved on behalf of Shiningbank Energy Income Fund by Shiningbank Energy Ltd.

A R Nelson

Director



Director

Consolidated Statements of Earnings and Unitholders' Equity

For the years ended December 31 (\$ thousands, except per Trust Unit amounts)	2002	2001
Revenues		
Oil and natural gas sales	\$ 142,661	\$ 170,714
Royalties	(26,470)	(38,857)
	116,191	131,857
Expenses		
Operating	31,583	28,257
General and administrative	4,143	3,788
Management fees	1,939	3,500
Interest on long term debt	5,109	5,675
Depreciation, depletion and amortization	60,034	47,032
Provision for future site restoration	2,862	2,470
Capital and large corporation taxes (note 6)	665	384
Internalization of management contract (note 9)	10,984	-
	117,319	91,106
Earnings (loss) before income taxes	(1,128)	40,751
Future income tax recovery (note 6)	(14,160)	(9,900)
Net earnings	\$ 13,032	\$ 50,651
Unitholders' equity, beginning of year	262,325	118,231
Proceeds on issue of Trust Units	54,724	176,241
Issue of Exchangeable Shares	6,475	-
Royalty distributions	(69,607)	(81,979)
Dividends to Manager	(517)	(819)
Unitholders' equity, end of year	\$ 266,432	\$ 262,325
Net earnings per Trust Unit		
Basic	\$ 0.40	\$ 2.08
Diluted	\$ 0.08	\$ 2.08

See accompanying notes to consolidated financial statements

Consolidated Statements of Cash Flows

For the years ended December 31 (\$ thousands)	2002	2001
Operating activities		
Net earnings	\$ 13,032	\$ 50,651
Items not requiring cash		
Depreciation, depletion and amortization	60,034	47,032
Internalization of management contract	6,475	-
Provision for future site restoration	2,862	2,470
Future income tax recovery	(14,160)	(9,900)
Cash flow from operating activities	68,243	90,253
Changes in non-cash working capital	1,690	(20,897)
	69,933	69,356
Financing activities		
Increase (decrease) in long term debt	(7,176)	18,078
Financing costs	-	(852)
Distributions to unitholders	(69,607)	(81,979)
Issue of Trust Units	54,724	98,607
Dividends paid	(517)	(819)
	(22,576)	33,035
Changes in non-cash working capital	5,357	(2,270)
	(17,219)	30,765
Total cash provided	\$ 52,714	\$ 100,121
Investing activities		
Property acquisitions	\$ (49,595)	\$ (44,902)
Deposits on future property acquisitions	(1,682)	-
Capital expenditures	(11,867)	(12,608)
Acquisition of business (note 3)	-	(49,300)
Long term investments	(655)	(1,100)
Proceeds on sale of fixed assets	11,470	8,280
Site restoration costs	(385)	(491)
Total cash used	\$ (52,714)	\$ (100,121)
Cash taxes paid	\$ 748	\$ 820
Cash interest paid	\$ 5,103	\$ 5,832

See accompanying notes to consolidated financial statements

Notes to Consolidated Financial Statements

For the years ended December 31, 2002 and 2001 (\$ thousands, except Trust Units and per Trust Unit amounts)

1. ORGANIZATION

Shiningbank Energy Income Fund (the "Fund") is an unincorporated open-end investment trust formed under the laws of the Province of Alberta pursuant to a trust indenture dated May 16, 1996 and subsequently amended. Operations commenced on July 1, 1996. The beneficiaries of the Fund are the holders (the "Unitholders") of trust units (the "Trust Units").

On April 6, 2001, the Fund and its wholly owned subsidiary 923720 Alberta Ltd. acquired approximately 95% of the outstanding common shares of Ionic Energy Inc. ("Ionic"). Effective May 4, 2001, the Corporation, 923720 Alberta Ltd. and Ionic were amalgamated, continuing as Shiningbank Energy Ltd.

Effective October 9, 2002, the Fund effected an internalization of its management by acquiring, through its wholly-owned subsidiary Shiningbank Holdings Corporation (SHC), all of the shares of Shiningbank Energy Management Inc., (the "Former Manager"). Subsequently the Former Manager and Shiningbank Energy Ltd. (the "Corporation") were amalgamated, continuing as Shiningbank Energy Ltd. (see note 9).

The trust indenture provides that 300,000,000 Trust Units may be issued. Each Trust Unit represents an equal fractional beneficial interest in any distributions from the Fund and in the net assets of the Fund on termination or winding up of the Fund. All Trust Units rank among themselves equally and rateably without discrimination, preference or priority. The trust indenture provides that Trust Units are redeemable at any time on demand by the Unitholders at amounts as determined by a market price formula. The total amount payable by the Fund in respect of all Trust Units tendered for redemption, however, may not exceed \$100,000 in any calendar month.

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared by management using Canadian generally accepted accounting principles. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Actual results could differ from those estimated.

In particular, the amounts recorded for depletion, depreciation and amortization of the petroleum and natural gas properties, deferred charges, and for site reclamation and abandonment are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

(a) Principles of consolidation

These consolidated financial statements include the accounts of the Fund, SHC and the Corporation.

(b) Fixed assets

The Fund follows the full cost method of accounting for petroleum and natural gas properties under which all acquisition and development costs are capitalized. Such costs include land acquisition, geological, geophysical and drilling costs for productive and non-productive wells and directly related overhead charges. Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs. Gains or losses upon disposition of such properties are not recognized unless the disposition would alter the depletion and depreciation rate by 20% or more.

The costs of fixed assets, plus a provision for future development costs of proved undeveloped reserves, are depleted and depreciated using the unit-of-production method based on estimated total proved reserves volumes, before royalties, as determined by independent engineers. Proved reserves are converted to a common unit of measure on the basis of their approximate relative energy content. Other miscellaneous assets are depreciated on a declining balance basis at 20% per annum.

The ceiling test has been computed using prices and costs in effect at the end of each year.

(c) Future site restoration costs

Estimated future site restoration and abandonment costs are provided for using the unit-of-production method based on estimated total proved reserves volumes. Costs are estimated by the Fund based on current regulations, costs, technology and industry standards. Actual site restoration and abandonment costs are charged against the liability as incurred.

(d) Income taxes

The Fund is a taxable trust under the Income Tax Act (Canada). Any taxable income is allocated to the Unitholders and therefore no provision for income taxes relating to the Fund is included in these financial statements.

The Corporation follows the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

The Corporation is a taxable Canadian corporation and is liable for tax on income that it retains. The Corporation is also subject to capital taxes in jurisdictions where such taxes apply and these taxes are deducted from distributions to Unitholders.

(e) Financial instruments

Financial instruments of the Corporation consist mainly of accounts receivable, accounts payable and long term debt. The carrying value of these items approximates their fair value at December 31, 2002. The Corporation also from time to time employs financial instruments to manage exposures related to interest rates, Canada/US exchange rates and commodity prices. These instruments are not used for speculative trading purposes.

(f) Trust Unit compensation plan

Consideration paid by employees and directors of the Corporation on the exercise of Trust Unit rights under the Fund's Trust Unit Rights Incentive Plan is recorded in Trust Units upon receipt. Effective January 1, 2002, the Fund adopted the recommendations of the CICA on accounting for stock-based compensation which apply to new rights issued after January 1, 2002. The Fund has elected to continue to account for stock-based compensation arrangements upon settlement.

(g) Joint ventures

Substantially all of the Fund's petroleum and natural gas activities are conducted jointly with others and, accordingly, these financial statements reflect only the Fund's proportionate interest in such activities.

(h) Per Trust Unit amounts

Basic earnings per Trust Unit is computed by dividing net earnings by the weighted average number of Trust Units outstanding for the year. Diluted net earnings per Trust Unit amounts reflect the potential dilution that could occur if securities or other contracts to issue Trust Units were exercised or converted to Trust Units.

Distributable income per Trust Unit is based on actual entitlements.

3. FIXED ASSETS

(a) Fixed asset additions

During 2002, the Fund acquired additional petroleum and natural gas properties in the amount of \$49,595,000 (2001 – \$44,902,000) which have been accounted for as purchases.

(b) Business acquisitions

Effective April 6, 2001, Shiningbank acquired the common shares of Ionic Energy Inc. ("Ionic"). The acquisition was accounted for by the purchase method and the results of operations of Ionic are included in the accounts from the effective date of acquisition.

Fair value of Shiningbank Trust Units	\$ 77,595
Cash consideration	45,000
Related fees and expenses	4,300
Cost of acquisition	\$ 126,895
Working capital deficiency	\$ (18,299)
Long term debt	(47,000)
Future income taxes	(73,500)
Petroleum and natural gas properties and equipment	265,694
Total consideration	\$ 126,895

4. LONG TERM DEBT

The Corporation has a \$170 million in revolving committed credit facility with a syndicate of four Canadian chartered banks. The borrowing base under the facility reduces to \$155 million on January 1, 2003 and has a 364 day extendable revolving period and a three year term. The revolving period ends on April 30, 2003 unless otherwise extended. In the event that the facility was not extended, there would be no amounts of principal required to be repaid in 2003. As at December 31, 2002, \$115.3 million was drawn against these facilities (December 31, 2001 – \$122.5 million). Borrowings under the facility bear interest at an annual rate ranging from the banks' prime rate to the banks' prime rate plus 0.95%, depending on the Corporation's total debt to cash flow ratio, or, at Shiningbank's option, the bankers' acceptance rate plus a stamping fee. The average borrowing rate at December 31, 2002 was 4.0% (December 31, 2001 – 3.3%). The facility is secured by a \$300 million floating charge debenture on all assets of the Corporation.

5. TRUST UNITS

(a) Authorized

300,000,000 Trust Units

(b) Trust Units

	2002		2001	
	Number	Amount	Number	Amount
Balance, beginning of year	29,117,937	\$ 337,246	16,828,712	\$ 161,005
Issued for cash	4,076,000	57,844	7,250,000	103,726
Issued upon business acquisition (note 3)	–	–	5,039,225	77,634
Commissions and issue costs	–	(3,120)	–	(5,119)
Balance, end of year	33,193,937	\$ 391,970	29,117,937	\$ 337,246

(c) Exchangeable Shares

On October 9, 2002, SHC issued 1,136,614 Exchangeable Shares in connection with the management internalization transaction. The Exchangeable Shares are exchangeable, at the option of the holder, into Trust Units for no additional consideration. As at December 31, 2002, 757,742 Exchangeable Shares were held in escrow to be released over periods of three to five years under the terms of two escrow agreements. The number of Trust Units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted on the distributions paid to unitholders divided by the ten day weighted average unit price preceding the record date. As at December 31, 2002, the exchange ratio was 1 to 1. The Exchangeable Shares are not eligible for distributions.

	2002	
	Number	Amount
Balance, beginning of year	-	\$ -
Issued to Former Manager shareholders	1,136,614	16,490
Deferred portion	(757,742)	(10,015)
Balance, end of year	378,872	\$ 6,475

(d) Trust Unit Options

The Trust Unit Option Plan was terminated effective June 30, 2001 and replaced with a Trust Unit Rights Incentive Plan described below. All of the outstanding options under the terminated plan were exercised prior to the termination.

	2002		2001	
	Number	Weighted average exercise price	Number	Weighted average exercise price
Balance, beginning of year	-	\$ -	175,000	\$ 9.98
Exercised	-	-	(175,000)	9.98
Balance, end of year	-	\$ -	-	\$ -

(e) Trust Unit Rights Incentive Plan

Effective July 1, 2001, a Trust Unit Rights Incentive Plan was established and approved by the Unitholders of Shiningbank to replace the former plan. A total of 2,132,845 units have been reserved for issuance under the plan. The initial exercise price of rights granted under the plan may not be less than the current market price of the Trust Units as of the date of grant and the maximum term of each right is not to exceed ten years. The exercise price of the rights is to be adjusted downwards from time to time by the amount, if any, that distributions to unitholders in any calendar quarter exceed a percentage of the Fund's consolidated net book value of fixed assets. At December 31, 2002, there were 1,059,000 rights outstanding, of which 452,333 were exercisable.

Rights	2002		2001	
	Number	Price	Number	Price
Balance, beginning of year	625,000	\$ 16.92	-	\$ -
Granted	485,000	13.97	625,000	17.25
Exercised	(51,000)	13.51	-	-
Balance before reduction of exercise price	1,059,000	\$ 15.71	625,000	\$ 17.25
Reduction of exercise price		(0.71)		(0.33)
Balance, end of period	1,059,000	\$ 15.00	625,000	\$ 16.92

The exercise price of the rights granted under the Fund's rights plan may be reduced in future periods in accordance with the terms of the rights plan. The amount of the reduction cannot be reasonably estimated as it depends upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and natural gas, determination of amounts to be withheld from future distributions to fund capital expenditures and the purchase and sale of property, plant and equipment. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

As it is not possible to determine the fair value of rights granted under the plan, compensation cost for proforma disclosure purposes has been determined based on the excess of the unit price over the exercise price at the date of the financial statements. For the year ended December 31, 2002 there would be a proforma reduction in net income of \$820,000 (\$0.03 per basic and diluted Trust Unit) for the estimated cost associated with rights granted on or after January 1, 2002 for which the exercise price is lower than the market value.

(f) Per Trust Unit amounts

Net earnings per Trust Unit have been calculated using the weighted average number of Trust Units outstanding during the year of 31,677,071 (2001 – 24,005,274).

6. INCOME TAXES

The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to the Corporation's and SHC's earnings before income taxes. This difference results from the following items:

	2002	2001
Taxable loss of the Corporation and SHC	\$ (43,700)	\$ (15,100)
Combined federal and provincial tax rate	42.12%	42.6%
Computed income tax recovery	(18,400)	(6,400)
Increase (decrease) in income taxes resulting from:		
Non-deductible Crown charges	100	100
Resource allowance	(300)	(1,200)
Change in tax rate	(860)	(500)
Other	700	(1,900)
Internalization of management contract	4,600	–
Future income tax recovery	(14,160)	(9,900)
Capital and large corporation taxes	665	384
Income and capital taxes	\$ (13,495)	\$ (9,516)

The components of the Corporation's and SHC's future income tax liability at December 31, 2002 are as follows:

	2002	2001
Future income taxes:		
Oil and natural gas properties	\$ 73,020	\$ 82,500
Provision for site restoration	(2,630)	(1,900)
Non-capital losses	(6,280)	(2,590)
Other	(770)	(510)
	\$ 63,340	\$ 77,500

7. RELATED PARTY TRANSACTIONS

Prior to the internalization transaction on October 9, 2002, the Former Manager provided services to the Fund and the Corporation pursuant to a management agreement. The Fund, through the Corporation, paid the Former Manager \$1,939,000 in 2002 (2001 – \$3,500,000) for management fees, together with \$4,397,000 (2001 – \$3,788,000) for recovery of general and administrative and financing expenses. These amounts have been charged to earnings. A further fee of \$721,000 (2001 – \$3,503,000) was paid in respect of acquisition fees, which amounts have been capitalized. Current liabilities at December 31, 2001 include \$1,807,000 payable to the Former Manager in respect of general and administrative expense recoveries and management fees.

8. FINANCIAL INSTRUMENTS

As at December 31, 2002, there are no significant differences between the carrying amounts and the fair value of accounts receivable, payable and long term debt. The Corporation is exposed to interest rate variance on the long-term debt disclosed in the balance sheet. Gains and losses on exchange rate and commodity price hedges are included in revenues upon the sale of related production provided there is reasonable assurance that the hedge is and will continue to be effective.

At December 31, 2002, Shiningbank held certain oil and natural gas hedge contracts, the terms of which are listed in the following table. The estimated market value at December 31, 2002, had the contracts been settled at that time, would have been a loss of \$1,321,000.

Period	Commodity	Volume	Price
November 1, 2002 – October 31, 2003	Gas	2 mmcf/d	\$4.22/mcf floor \$8.70/mcf ceiling
November 1, 2002 – March 31, 2003	Gas	5 mmcf/d	\$4.22/mcf floor \$7.69/mcf ceiling
November 1, 2002 – March 31, 2003	Gas	5 mmcf/d	\$4.74/mcf floor \$7.52/mcf ceiling
April 1, 2003 – October 31, 2003	Gas	5 mmcf/d	\$5.38/mcf
April 1, 2003 – October 31, 2003	Gas	5 mmcf/d	\$5.01/mcf floor \$7.06/mcf ceiling
January 1, 2003 – December 31, 2003	Oil	500 bbl/d	US\$24.00/bbl floor US\$27.62/bbl ceiling



Subsequent to December 31, 2002, the Corporation entered into three natural gas hedge contracts. The first is for the period from April 1, 2003 to October 31, 2003 totaling 5 mmcf/d with a floor of \$5.27 per mcf and a ceiling of \$8.43 per mcf; the second is for the period from April 1, 2003 to December 31, 2003 totaling 13 mmcf/d with a fixed price of \$7.75 per mcf and the third is for calendar 2004 for 11 mmcf/d at a fixed price of \$6.44 per mcf. In addition, the Corporation entered into an oil hedge contract for the period from July 1, 2003 to December 31, 2003 totaling 500 bbl/d with a floor of US\$26.00 per bbl and a ceiling of US\$30.10 per bbl.

As at December 31, 2002, the Corporation held an interest rate swap for \$10.0 million at an interest rate of 3.48%, expiring October 30, 2004. The estimated market value at December 31, 2002, had the contract been settled at that time, would have been a loss of \$76,000.

9. ACQUISITION OF SHININGBANK ENERGY MANAGEMENT INC.

Effective October 9, 2002, the Fund acquired all of the outstanding shares of Shiningbank Energy Management Inc., the Former Manager of the Fund. Total consideration for the transaction consisted of a cash payment of \$2.91 million plus 1,136,614 Exchangeable Shares of SHC. Total consideration was reduced by \$1.8 million to provide for performance/retention bonuses to be paid to employees over the next five years.

Total consideration:	
Cash	\$ 2,910
Exchangeable Shares issued	16,490
Costs associated with the transaction	1,195
Total purchase price	\$ 20,595

Prior to the acquisition, the Fund paid fees to the Former Manager of 3.25% of net operating income, a fee of 1.5% on the purchase price of acquisitions and a quarterly scheduled dividend in accordance with the terms of the management agreement. The acquisition resulted in the elimination of all fees and dividends under the management contract which would have been in effect.

Exchangeable Shares in the amount of \$10.0 million are subject to escrow provisions and have been deferred and will be amortized into income as internalization of management contract expense over the specific vesting periods from 2003 to 2007. For the year ending December 31, 2002, \$978,200 has been recorded as expense representing the amortization of these escrowed Exchangeable Shares.

10. SUBSEQUENT EVENTS

On February 11, 2003, the Fund issued 3,841,000 Trust Units at a price of \$15.00 for net proceeds of \$54,734,250.

Subsequent to December 31, 2002, the Fund entered into an acquisition agreement to acquire a significant package of natural gas producing properties and undeveloped land in west-central Alberta for approximately \$133.3 million. The effective date of the acquisition is January 1, 2003 and it is expected to close on or about March 28, 2003.

Five-Year Financial and Operating Review

FINANCIAL

(\$000s, except Trust Unit amounts)	2002	2001	2000	1999	1998
Gross revenues	\$ 142,661	\$ 170,714	\$ 104,772	\$ 44,129	\$ 30,163
Royalties	(26,470)	(38,857)	(21,565)	(7,909)	(4,950)
Operating expenses	(31,583)	(28,257)	(14,959)	(11,446)	(9,756)
Operating netback	84,608	103,600	68,248	24,774	15,457
General and administrative	4,143	3,788	2,577	2,102	1,875
Management fees	1,939	3,500	2,134	849	638
Interest	5,109	5,675	3,020	2,175	1,797
Internalization of management contract	4,509	-	-	-	-
Other	665	384	477	135	29
Cash flow	68,243	90,253	60,040	19,513	11,118
Depreciation, depletion and amortization	60,034	47,032	19,825	13,781	11,342
Provision for site restoration	2,862	2,470	1,351	1,069	917
Internalization of management contract	6,475	-	-	-	-
Future income tax recovery	(14,160)	(9,900)	1,100	-	-
Net earnings (loss)	\$ 13,032	\$ 50,651	\$ 37,764	\$ 4,663	\$ (1,141)
Cash flow	\$ 68,243	\$ 90,253	\$ 60,040	\$ 19,513	\$ 11,118
Capital expenditures and site restoration	(12,252)	(4,819)	(5,838)	(2,129)	(1,388)
Internalization of management contract	4,509	-	-	-	-
Working capital adjustments	9,107	(3,455)	(11,792)	16	1,832
Distributable income	\$ 69,607	\$ 81,979	\$ 42,410	\$ 17,400	\$ 11,562
Distributions per Trust Unit	\$ 2.16	\$ 3.40	\$ 2.76	\$ 1.60	\$ 1.43
Long term debt	115,283	122,459	57,381	35,519	39,602
Acquisition and development costs	63,144	323,204	116,362	28,283	30,578
Unitholders' equity	266,432	262,325	118,231	68,935	53,225
Total assets	494,303	503,065	232,773	118,242	103,068
Trust Units outstanding at year end (000s)	33,194	29,118	16,829	11,792	8,689
Average Trust Units outstanding during year (000s)	31,677	24,005	14,167	10,660	7,910
Trading history					
High	\$ 15.95	\$ 18.70	\$ 18.50	\$ 11.40	\$ 10.30
Low	\$ 10.00	\$ 11.85	\$ 9.90	\$ 9.45	\$ 7.95
Close	\$ 15.15	\$ 13.97	\$ 17.00	\$ 10.65	\$ 10.00
Volume (millions of units)	25.0	27.1	9.0	5.1	5.0

OPERATING

	2002	2001	2000	1999	1998
Production					
Oil (bbl/d)	2,054	2,013	1,402	1,298	1,208
Gas (mmcf/d)	64.2	61.6	35.7	27.5	24.7
NGL (bbl/d)	1,454	1,288	962	697	478
Oil equivalent (boe/d) (6:1)	14,214	13,564	8,312	6,572	5,796
Natural gas weighting	75%	76%	72%	70%	71%
Average sales price (after hedging)					
Oil (\$/bbl)	\$ 36.31	\$ 35.67	\$ 41.95	\$ 25.85	\$ 17.65
Gas (\$/mcf)	\$ 4.32	\$ 5.80	\$ 5.45	\$ 2.68	\$ 2.23
NGL (\$/bbl)	\$ 26.59	\$ 29.59	\$ 34.52	\$ 19.54	\$ 13.65
Oil equivalent (\$/boe) (6:1)	\$ 27.50	\$ 34.48	\$ 34.44	\$ 18.40	\$ 14.26
Established reserves					
Oil and NGL (mmbbl)	11,893	12,044	9,361	7,882	6,680
Natural gas (bcf)	210.0	210.8	151.3	85.4	81.0
Oil equivalent (mboe @ 6:1)	46,890	47,171	34,583	22,116	20,174

Corporate Information

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Paddock Lindstrom & Associates Ltd.
Calgary, Alberta

LEGAL COUNSEL

Gowling Lafleur Henderson LLP
Calgary, Alberta

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
Symbol: SHN.UN

BOARD OF DIRECTORS

Arne R. Nielsen

Executive Chairman

David M. Fitzpatrick

President & Chief Executive Officer

D. Grant Gunderson

Director

Edward W. Best

Director

Warren D. Steckley

Director

OFFICERS

Arne R. Nielsen

Executive Chairman

David M. Fitzpatrick

President & Chief Executive Officer

Bruce K. Gibson

*Vice President,
Finance & Chief Financial Officer*

Gregory D. Moore

Vice President, Operations

Terry P. Prokopy

Vice President, Land

Richard W. Clark

Corporate Secretary

NOTICE OF MEETING

The Special and Annual General Meeting of the unitholders of Shiningbank Energy Income Fund and the Annual General Meeting of Shiningbank Energy Ltd. will be held on Tuesday, May 6, 2003 at 3:00 p.m. (local time) in the McMurray Room of the Calgary Petroleum Club, 319 – 5th Avenue S.W. Calgary, Alberta. Unitholders are encouraged to attend, and those unable to do so are asked to complete and return the Form of Proxy.

OUR EMPLOYEES AND CONSULTANTS

Mark Adams	Les Kingdon
Pabla Andaur	Todd Klippenstein
Ray Bahr	Tom Kokotailo
Kristine Beard	Darcy Lamoureux
Chad Beaulieu	George Mahan
Dennis Betts	Pierre Marchand
Jason Bosma	Ian Martinot
Irvin Bouck	Kathy Matheson
Robert Bougie	Joe McAvoy
Gisele Bourgeois	James McBeth
Judy Britton	Debbie McBride
Irene Britton	Jim McIntosh
Brenda Brodie	Gordon McLean
Debbie Carver	Harold McLean
S. Ken Chalmers	Jana McLean
Paul Codd	Rob Miller
Sandy Cunningham	Rhonda Mitchell
Bill DeGroot	Greg Moore
Richard Eric	Ben Morris
Bill Fincaryk	Ken B. Morrison
Dave Fitzpatrick	Brenda Mychasiuk
Darilyn Fortuna	Arne Nielsen
Jim Frey	Joe Ollenberger
Trevor Fulton	Brian Ontko
Angie Furdievich	Roger Palmer
Marilyn Gardner	Brenda Parker
Bruce Gawalko	Terry Prokopy
Randy Gerber	Bruce Richert
Don Geherman	Terry Robichaud
Bruce Gibson	David Russell
Ian Gillies	Luc Sabourin
Alan Glessing	Patricia Sardinha
Brad Granley	Lawrence Schaff
Mark Gray	Brad Schuck
Indy Grewal	Irv Scott
Trevor Hans	Laura Silbernagel
Dave Hendrickson	Malcolm Sills
Kari Herman	Darrell Spink
Jeannette Hibbert	Brad Stack
Paul House	Lorraine Straus
Bill Hughes	Dorsey Sunderland
Andrea Huitema	Eric Tjostheim
Connie Hutchison	Ed Wall
Kelly Jahner	Bill Warren
Line Johnson	Aaron Watt
Paul Johnston	Dan Williams
Harold Junck	Donna Wilson
Jerry Keeler	Rose Wong
Sonia Kelly	Cory Yee
Doug Kidd	Gail Zirk

ABBREVIATIONS

bbl	barrels of oil or natural gas liquids
bcf	billion cubic feet of natural gas
boe	barrels of oil equivalent (6,000 cubic feet of natural gas is equivalent to one barrel of oil)
/d	per day
mbbl	thousand barrels
mboe	thousand barrels of oil equivalent
mmboe	million barrels of oil equivalent
mcf	thousand cubic feet of natural gas
mmcf	million cubic feet of natural gas
mmbtu	million British thermal units
NGL	natural gas liquids
tcf	trillion cubic feet of natural gas

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